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NEW ELECTRIC POWER TECHNOLOGIES

Problems and Prospects for the 1990s

SUMMARY

CONGRESS OF THE UNITED STATES
Office of Technology Assessment
Washington, D. C. 20510

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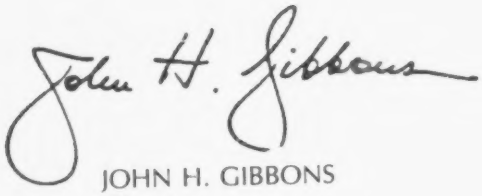
Foreword

This report responds to a request from the House Committee on Science and Technology and its Subcommittee on Energy Development and Applications to analyze a range of new electric power generating, storage, and load management technologies.

OTA examined these technologies in terms of their current and expected cost and performance, potential contribution to new generating capacity, and interconnection with the electric utility grid. The study analyzes increased use of these technologies as one of a number of strategies by electric utilities to enhance flexibility in accommodating future uncertainties. The study also addresses the circumstances under which these technologies could play a significant role in U.S. electric power supply in the 1990s. Finally, alternative Federal policy initiatives for accelerating the commercialization of these technologies are examined.

OTA received substantial help from many organizations and individuals in the course of this study. We would like to thank the project's contractors, who prepared some of the background analysis, the project's advisory panel and workshop participants, who provided guidance and extensive critical reviews, and the many additional reviewers who gave their time to ensure the accuracy of this report.



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Brian E. Curry
Northeast Utilities

Janice G. Hamrin
Independent Energy Producers

William B. Harrison
Southern Co. Services, Inc.

Eric Leber
American Chemical Society[1]

Paul Maycock
Photovoltaic Energy Systems

Charles McCarthy
Southern California Edison Co.

Anne F. Mead
New York State Public Service Commission

Alan Miller
World Resources Institute

Bruce W. Morrison
Westinghouse Electric Corp.

Fred Schweppe
Massachusetts Institute of Technology

Jon Veigel
North Carolina Alternative Energy Corp.

[1]Formerly with the American Public Power Association.

NOTE: OTA appreciates and is grateful for the valuable assistance and thoughtful critiques provided by the advisory panel members.

OTA Project Staff—New Electric Power Technologies

Lionel S. Johns, *Assistant Director, OTA*
Energy, Materials, and International Security Division

Richard E. Rowberg, *Energy and Materials Program Manager*

Project Staff

Peter D. Blair, *Project Director*

Mary Procter[1]

David Kathan (Economic and Financial Analysis)

Robert Lempert (Solar Technologies)

Lynn Luderer (Regional Analysis)

David Strom (Interconnection)

Nicholas Sundt (Technologies and Industry Structure)

Administrative Staff

Lillian Chapman Edna Saunders

Contractors and Consultants

Gibbs & Hill, Inc., New York, NY
Battelle Memorial Institute, Columbus, OH
Investor Responsibility Research Center, Inc., Washington, DC
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Peter Hunt Associates, Alexandria, VA
Electrotek Concepts, Inc., Mountain View, CA
Strategies Unlimited, Inc., Palo Alto, CA
E. S. Pechan Associates, Washington, DC
Howard Geller, Washington, DC
Paul Maycock, Arlington, VA
David Sheridan, Chevy Chase, MD

Other OTA Contributors

Jenifer Robison Robert M. Friedman Eugene Frankel Paula Wolferseder

[1]Project Director through May 1984.

Other Contributors

Many institutions and individuals contributed to this report by providing information, advice, and substantive reviews of draft materials. Institutions completing major reviews and providing considerable information are listed below; individuals are noted in the full report along with other reviewers and contributors.

American Public Power Association

California Energy Commission

Congressional Research Service

Edison Electric Institute

Energy Information Administration

Electric Power Research Institute

Environmental Protection Agency

Federal Energy Regulatory Commission

North American Electric Reliability Council

National Regulatory Research Institute

Pacific Gas & Electric Co.

Renewable Energy Institute

Solar Energy Research Institute

Southern California Edison Co.

Tennessee Valley Authority

U.S. Department of Energy

New Electric Power Technologies

Problems and Prospects for the 1990s

OVERVIEW AND FINDINGS

During the 1970s, the environment within which utilities made investment decisions changed from a relatively predictable continuation of past trends to a highly uncertain and complicated maze of interrelated financial, regulatory, and technology considerations. As electric utilities face the 1990s, the experiences of the 1970s have made them much more wary of the financial risk of guessing wrong and overcommitting to large central station coal and nuclear plants. At the same time, the possibility of being unable to meet electricity demand exists, causing growing concern among utilities as the next decade approaches.

As a result, utilities are now taking steps to enhance their flexibility in accommodating future uncertainties. In addition to continued and primary reliance on conventional technologies, supplemented by coal combustion technology enhancements to reduce pollution emissions and increase efficiency, utilities are considering a variety of less traditional options. These include life extension and rehabilitation of existing generating facilities, increased purchases from and shared construction programs with other utilities, diversification to nontraditional lines of business, increased reliance on less capital-expensive options such as load management and conservation, and smaller scale power production from a variety of conventional and alternative energy sources. Such options offer utilities the prospects of more rapid response to demand fluctuations than traditional, central station powerplants.

The Role of New Technologies

This report focuses on a number of alternative generating technologies, as well as on energy storage and load management technologies that are new or have not traditionally been used by utilities or other power producers. It examines their technical readiness and the conditions under which they could contribute to meeting electricity demand in the 1990s. The study does not examine in detail the more traditional technologies of central station coal or nuclear, nor does it analyze advanced nuclear or combined-cycle systems and enhancements to pulverized coal plants such as supercritical boilers, limestone injection, or advanced scrubber systems. In addition, we do not discuss more mature renewable technologies such as low-head hydropower or refuse- or wood-fired steam plants. Many of these options are discussed in other OTA reports. It is important to note,

however, that these traditional options and their variations are likely to remain the principal choice of electric utilities in the 1990s.

It is convenient to divide the technologies considered in this assessment into two basic groups in order to discuss appropriate policy options:

1. The first consists of technologies envisioned primarily for direct electric utility applications and includes integrated gasification/combined-cycle (IGCC); large (>100 MW) atmospheric fluidized-bed combustors (AFBC); large (>100 MW) compressed air energy storage (CAES) facilities; large (>50 MW) geothermal plants; utility-owned, fuel cell powerplants; and solar thermal central receivers.
2. The second group consists of technologies that are characterized as suitable either for utility or nonutility applications, and includes small (<100 MW) AFBCs in nonutility cogeneration applications; small (<100 MW) CAES; fuel cells; small (<50 MW) geothermal plants; batteries; wind; and direct solar power generating technologies such as photovoltaics and parabolic dish solar thermal.

Virtually all of these technologies offer the potential for sizable deployment in electric power generation applications beyond the turn of the century. The potential is high because these technologies offer one or more advantages over most conventional generating alternatives. In general, they would constitute a diverse array of generation equipment capable of flexibly meeting future demand growth and increasing the clean and efficient utilization of abundant domestic energy resources. Some are **smaller scale technologies with modular designs that permit capacity additions to be made in small increments with less concentration of financial assets and short lead-times between commitment and coming "on-line."** Utilities may be able to realize notable financial benefits from smaller scale capacity additions, even when the capital cost per kilowatt of smaller units is as much as 10 percent more than that of large-scale capacity additions. Other attractive features of these technologies include **reduced environmental impacts, the potential for fewer siting and regulatory barriers, and improved efficiency and fuel flexibility**.

Despite these long-term advantages, however, **at the current rate of development very few of these technologies are likely to be deployed extensively enough in the 1990s to make a significant contribution to U.S. electricity supply**. In both groups of technologies, the ultimate goal of research, development, and demonstration is to reduce costs and increase performance so that these new technologies can compete with more traditional technologies.

For the first group, the likelihood of long preconstruction and construction lead-times—up to 10 years—is the primary constraint. Although these technologies have the potential for much shorter lead-times—5 to 6 years—problems associated with any new, complex technology may require construction of a number of plants before that potential is met. If the longer lead-times are needed, deployment in the 1990s will be limited because of the short time remaining to develop the technologies to a level utilities would find acceptable for commercial readiness.

Technologies in the second group are likely to have shorter lead-times and are often smaller in generating capacity. **For most of them to make a significant contribution in the 1990s, however, their development will have to be stepped-up in order to reduce cost to levels acceptable to utility decisionmakers and nonutility investors, and to resolve cost and performance uncertainties**.

In addition to new generating and storage technologies, **load management** is being pursued actively by some utilities. **Widespread deployment among utilities in the 1990s, however, will depend on: continued experimentation by utilities to resolve remaining operational uncertainties; further refinement of load management equipment including adequate demonstration of communications and load control systems; development of incentive rate structures; and a better understanding of customer response to different load controls and rate incentives.** For load management as well as certain generating technologies—specifically fuel cells, photovoltaics, solar thermal technologies, and batteries—economies of scale in manufacturing could reduce cost substantially. Of course, these reduced costs will not be realized without substantial demand from utilities or other markets.

Finally, the relative advantages of both groups of new generating technologies and load management varies by region. Factors such as demand growth rates, age and type of existing generating facilities, natural resource availability, and regulatory climate all influence technology choice by utility and nonutility power producers.

Steps for Accelerated Development and Deployment

If electricity demand growth should accelerate by the early 1990s, the first choice of utilities is likely to be conventional central station generation capacity. Because of many well-documented problems, however, there may be significant risks in relying on this choice alone and utilities could face serious problems in meeting demand. As a consequence, it may be prudent to accelerate the availability of the technologies discussed in this study. Although not all the technologies would be needed under such conditions, if they were available, the market would be able to offer a more versatile array of choices to electricity producers.

The steps necessary to make these technologies available vary. **With the first group of technologies, it is necessary first to resolve cost and performance uncertainties within the next 5 to 6 years, and then to assure the 5- to 6-year lead-time potential is met for early commercial units**.

In the wake of the experiences of the last decade, utility decisionmakers, in particular, are now very cautious about new technology, and they impose rigorous performance tests on technology investment alternatives. **This conservatism makes advanced commercial demonstration projects even more important.** For the **basic** designs of the AFBC, IGCC, and utility-scale geothermal plants, **the current development and demonstration schedule appears adequate to allow these technologies to be ready by the**

1990s. The cooperative industry-government demonstration efforts, managed by the utilities, have a good track record. **The transition from demonstration to early commercial units, however, will have to be accelerated if the technologies are to produce a significant amount of electricity in the 1990s**. Moreover, variations in basic designs or more advanced designs to enhance performance characteristics further will require additional research and development.

Lead-times being experienced by some early commercial projects in both groups of technologies have been longer than anticipated, partially due to the time required for regulatory review. **Working closely with regulators and taking steps to assure quality construction for the early commercial plants could greatly assist the achievement of shorter lead-times. Emphasis on smaller unit size—200 to 300 MW—would facilitate these actions. For the technologies in the second group defined earlier, where cost and performance are of greatest concern, one approach to accelerating development would be to increase or concentrate Federal research and development efforts on these technologies. This could be particularly effective for photovoltaics, solar thermal parabolic dishes, and advanced small geothermal designs**.

There are other approaches, though, which can assist Federal efforts in technology development. The reemergence of nonutility power production as a growing industry in the United States is providing, and can continue to provide, an important test bed for some of these new generating technologies. **For nonutility power producers, the Renewable Energy Tax Credit (RTC) and the recovery of full utility avoided costs under the Public Utility Regulatory Policies Act of 1978 (PURPA) have been crucial in the initial commercial development and deployment of wind and solar power generating technologies**. In particular, with declining direct Federal support for renewable technology development, **the RTC has supported both development of advanced designs as well as commercial application of mature designs**.

Without some continuation of favorable tax treatment, based either on capacity or production, development of much of the domestic renewable power technology industry may be significantly delayed. Some technologies such as geothermal and wind have advanced to the point, however, where industry probably would continue development, although at a much slower pace, even if the RTC were withdrawn.

Cooperative agreements among utilities, public utility commissions, and the Federal Government can provide another mechanism for supporting advanced commercial demonstration projects of technologies from both groups. A portion of such projects could be financed with an equity contribution from the utility and the remainder through a "ratepayer loan" granted by the public utility commission, possibly guaranteed by the Federal Government.

Other Actions

The rate of deployment of new generating technologies also will be affected by the extent to which utilities and nonutility power producers can resolve such issues as interconnection standards, coordination with utility resource plans, and procedures for gaining access to transmission for interconnection and wheeling of power to customers or other utilities.

The contribution of new generating technologies is likely to be enhanced if utilities are allowed to enjoy the full benefits afforded to qualifying facilities under PURPA and if the restrictions on the use of natural gas in power generation are removed. The latter would allow the use of natural gas as an interim fuel during the development of "clean coal" technologies, and give utilities and nonutility power producers added flexibility.

The new generating technologies that appear to show the most promise for significant deployment in the 1990s are those that can serve additional markets beyond the domestic utility grid. Such markets are particularly important while the need for new electric generating capacity is low, and while the cost and performance of these technologies are uncertain in grid-connected applications. Indeed, **if priorities must be set in supporting developing technologies, it is important to note that broad market appeal is as important as commercial readiness to their timely development.** In this respect, Federal efforts to help industry exploit foreign markets could be especially important.

The rate of new generating technology deployment also is tied closely to future trends in avoided cost and other provisions established by PURPA. **Long-term energy credit and capacity payment agreements between utilities and nonutility power producers could accelerate deployment. So could mandatory minimum rates or fixed price schedules for utility payments to nonutility power producers or for use as a basis for cost recovery by utilities themselves.** Finally, to increase the number of **nonutility power projects** employing new electric generating technologies, steps to streamline the mechanisms for wheeling of power through utility service territories might open up new markets for the electricity they produce and thereby stimulate their development.

INTRODUCTION

The Policy Context

For the U.S. electric power industry, the 1970s was a decade of unprecedented change. Beginning with the 1973-74 Arab oil embargo, forecasts of electricity demand growth and costs, based solely on past trends, proved virtually useless. Utility decisionmakers found themselves caught in a complicated and uncertain maze of interrelated financial, regulatory, and technological considerations.

Utilities had to pay, on average, 240 percent more for oil and 385 percent more for natural gas, in real dollars, in 1984 than in 1972. These price increases drove them to "back out" of oil- and gas-fired generation and in favor of coal and nuclear plants. Oil dropped from 16 to 5 percent in the utility fuel mix and gas from 22 to 12 percent between 1972 and 1984. But construction costs of new powerplants, particularly nuclear, rose dramatically during this period due to a combination of factors—increased attention to environmental and safety issues (leading to extended construction lead-times and added equipment costs), an unpredictable regulatory environment, an inflation-driven doubling of the cost of capital, and poor management in some cases. The higher costs of fuel and capital meant higher electricity costs, and utilities sought higher rates for the first time in decades. In addition, most utilities seriously underestimated the price elasticity of electricity demand. Growth in demand plummeted from 7 percent a year to less than 2.5 percent by the end of the decade as consumers used less electricity and used it more efficiently.

During the 1970s some electric utilities were brought to the brink of bankruptcy when forced to cancel large, unneeded powerplants; commitments to these plants had been made long before it was realized that electricity demand had been overestimated. The eroding revenue base accompanying declining demand growth coupled with the increasingly costly construction programs already underway left the industry for the most part struggling financially as bond ratings and stock prices fell precipitously.

Even now in the mid-1980s, although utilities have for the most part recovered from the financial trauma of the 1970s,[1] the scars remain. The process by which utilities initiate, analyze, and implement investment decisions was changed fundamentally by the 1970s experience. In the 1960s, power system planners analyzed capacity expansion plans based on life cycle electricity costs of alternative plans. System planners now work much more closely with financial planners to analyze carefully the cash flow of the alternatives as well as the flexibility of alternative plans in accommodating unanticipated changes in demand, capital cost, interest rates, environmental regulation, and a host of other considerations. In short, their decisionmaking process has become much more financially cautious as well as more complex.

While power system planners for most utilities continue to focus on conventional generating technologies, as well as advanced combined-cycle systems or enhancements to pulverized coal plants such as supercritical boilers, limestone injection, or advanced scrubber systems, they now consider a much broader range of strategic options, including: life extension and rehabilitation of existing generating facilities; increased purchases from and shared construction programs with neighboring utilities; diversification to nontraditional lines of business; increased reliance on load man-

[1]Actually, even though 1984 was a very good year for utility stocks on average, as of early 1985, utilities fall roughly into three categories of stock performance: some with little or no construction are quite strong, some with low to modest construction programs are stable but lackluster in performance, and finally some with large nuclear facilities under construction (or recently canceled) are still doing very poorly.

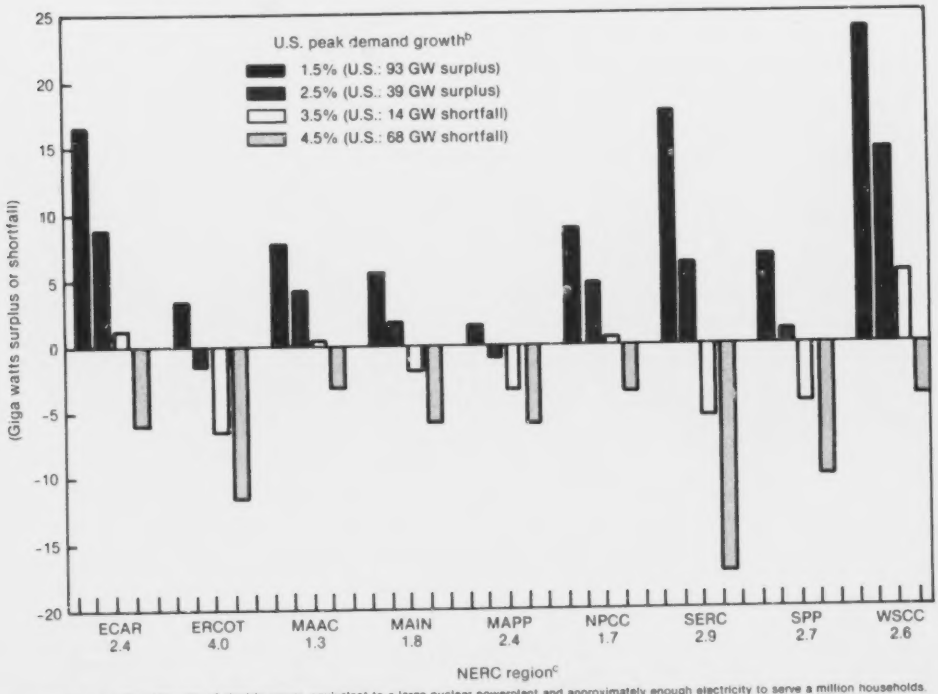
agement; and increased use of small-scale power production from a variety of both conventional and alternative energy sources. In addition, most utilities have greatly expanded their conservation programs, both because it now offers the lowest cost means of meeting demand in many cases, and it provides the utility with a way to reduce future demand uncertainty. In considering these various options, utilities hope to chart an investment course that will enable them both to meet the largely unpredictable demand for electricity in the future and to maintain their financial health.

The most critical legacy of the 1970s is the uncertainty in electricity demand growth. After 1972, not only did the average annual demand growth rate drop to less than a third of that of the previous decade, but the year-to-year changes became erratic as well. Users of electricity were able to alter the quantity they used much more quickly than utilities could accommodate these changes with corresponding changes in generating capacity. Moreover, as of 1985, there is saturation in some markets—many major appliances in homes—and the future of industrial demand is clouded as many large industrial users of electricity, such as aluminum and bulk chemicals, are experiencing decline in domestic production due to foreign competition. At the same time, rapid growth continues in other areas such as space conditioning for commercial buildings, industrial process heat, and electronic office equipment. Predicting the net impact of these offsetting factors, along with trends toward increased efficiency, has greatly complicated the job of forecasting demand.

Since requirements for new generating capacity over the next two decades depends primarily on electricity demand growth (as well as the rate at which aging plants are replaced with new capacity and, in some regions, net imports of bulk power from other regions), planning for new capacity has become a very risky process. To illustrate the demand uncertainty, this assessment looks at a range of different growth rates—1.5, 2.5, 3.5, and 4.5 percent increases in average annual electricity demand through the end of the century. This range is based on analysis carried in the 1984 OTA study, *Nuclear Power in an Age of Uncertainty*. Figure 1 correlates these different demand growth rates with the currently planned generating capacity for 1993 in the regions of the United States defined by the North American Electricity Reliability Council (NERC)—the NERC regions are defined in figure 2. In all regions, capacity surpluses are now projected if annual demand growth is 1.5 percent; and in seven of the nine regions, there would be capacity surpluses if demand growth is 2.5 percent. But a 3.5 percent growth rate could mean capacity shortfalls in five of the nine regions; and with a 4.5 percent growth, there could be shortfalls in all regions.

At the center of the policy debate over the future of electricity supply is the mix of power generation technologies that will be deployed by either utility or nonutility power producers over the next several decades. Those anticipating a strong resurgence in electricity demand in the 1990s support the building of more large powerplants. They cite economies of scale of such plants that, in their view, would minimize electricity costs over the long run. Others, who believe demand growth to be more uncer-

Figure 1.—1993 U.S. Generating Capacity Surplus or Shortfall Under Alternative Peak Load Growth Scenarios[a]



one gw = 1 million kilowatts of electric power, equivalent to a large nuclear powerplant and approximately enough electricity to serve a million households.

[a]Surplus or shortfall is the projected 1993 capacity less 1993 projected peak load (including 20% reserve margin).

[b]Average annual growth in peak demand for 1983-1993; regional growth rates for the 2.5% reference case are given at the bottom of the chart.

[c]The North American Electric Reliability Council regions are defined in figure 2.

SOURCE: Reference projections for installed generating capacity, 2.5 percent average annual growth (national), and regional growth rates are reported in North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993* (Princeton, NJ: NERC, 1984).

tain, favor a strategy of flexibility which includes the possibility of small-scale capacity additions as well as increased reliance on other methods of dealing with demand uncertainty such as conservation and load management.

Complicating this controversy is the utilities' evolving attitude toward new technology, another consequence of the 1970s. While traditionally conservative in adopting new technology, the electric utility industry has grown particularly cautious in the wake of its experience with nuclear power. Utilities now impose very rigorous economic performance tests on new technology investments. Perhaps because of this caution, projects initiated by nonutility power producers under PURPA since 1978 have served as the principal test bed for first generation commercial applications of many new generating technologies.

The Players

Any Federal policy decision affecting the electric power industry affects a wide range of interests. The changing conditions of the 1970s along with increased activity in new technology development have increased the num-

Figure 2.—Map of North American Electric Reliability Council (NERC) Regions

ECAR	East Central Area Reliability Coordination Agreement	NPCC	Northeast Power Coordinating Council
ERCOT	Electric Reliability Council of Texas	SERC	Southeastern Electric Reliability Council
MAAC	Mid-Atlantic Area Council	SPP	Southwest Power Pool
MAIN	Mid-America Interpool Network	WSCC	Western Systems Coordinating Council
MAPP	Mid-continent Area Power Pool		

SOURCE: North American Electric Council (NERC), *NERC At A Glance* (Princeton, NJ: NERC, 1984).

ber of participants who affect the industry. Each brings a very different perspective to electricity policy issues, especially with respect to new technologies. These participants are as follows:

- **Electric utilities** themselves, both public and private, differ widely in financial health, existing facilities and fuel use, and in their attitudes toward new technology.
- **Nonutility power producers** have reemerged as a potentially important force in the future of electric power in the United States, particularly with respect to application of new technologies. With the enactment of PURPA, such producers (which includes all entities other than electric utilities) have begun to provide a noteworthy source of innovation in electric power generation. The relationship which evolves between these electricity producers and utilities will certainly influence the degree of deployment of new power generating technologies over the next two decades.
- **State public utility commissions** exert considerable influence over utility choices by what is permitted to enter the rate base. Commissions

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differ widely in their attitudes toward treatment of research and development, rate structure design, cost overruns of construction programs, as well as toward new technology.

- **Federal regulators** such as the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, and the Environmental Protection Agency, in carrying out their assigned missions, affect the electric power industry profoundly. The prospect of extensive deployment of new technologies over the next several decades may hinge as much on the regulations promulgated by these agencies as on the competitive cost and performance of the technologies.
- **Ratepayers'** response to electricity prices as well as their attitudes on issues such as nuclear power costs, nuclear safety, coal pollution, and acid rain, etc., will play major roles in determining the future of the electric power industry. In particular, ratepayers' response to prices, i.e., their demand for electricity, and attitudes on electricity-supply-related issues, will largely determine the technologies that will be employed in power generation.
- **Investors'** attitudes on the comparative risks in selecting future utility and nonutility power generation projects are important considerations and will affect the financial health of both industries. As the utility industry recovers from a financially troubled period, the degree to which investors are willing to put their money into large new generating plants again will greatly affect utility investment decisions. Similarly, the access of new electricity-generating technologies to traditional (other than venture) capital sources, which is so critical to the continued development of many of these technologies, will depend on investors' perceptions of the technologies' cost and performance prospects.
- **Vendors of conventional power generating technology** have enjoyed a long relationship with the electric utility industry. This relationship heavily influences new technology investment decisions.
- **Vendors of developing technologies** include many businesses that have not traditionally dealt with the electric utility industry. New technology developers, which in many cases also include traditional vendors, range from giant petroleum companies and aerospace firms to small independent firms. In many cases, the newcomers are only beginning to establish working business relationships with electric utilities and other nonutility power producers. For some technologies, these firms are much more diverse in terms of age, size, financial position, etc., than conventional technology vendors. The relationship between such firms and the utilities as well as nonutility power producers is still evolving and will affect future investment decisions.
- **Research and development establishments** such as the U.S. Department of Energy and the Electric Power Research Institute (EPRI) are now important forces in the development of new electric power technologies. Traditionally, until the 1970s, research, development, and demonstration of new electric power technologies was primarily within the province of a handful of equipment vendors cited above, in some cases supported by the Federal Government. Increasing Federal in-

volvement in energy research and development in the 1970s and establishment of the EPRI in 1972 contributed to expanding the range of public and private entities involved in commercial development of new electric technologies.

NEW GENERATING TECHNOLOGIES FOR THE 1990s

A number of developing technologies for electric power generation are beginning to show considerable promise as future electricity supply options. Some of these technologies, such as atmospheric fluidized-bed combustion (AFBC) and integrated coal gasification/combined-cycle conversion (IGCC) and fuel cells, could pave the way for clean and more efficient power generation using domestic coal resources.

In box A, the renewable[2] and nonrenewable technologies considered in this assessment are listed and briefly discussed. Table 1 shows those technologies grouped according to the sizes and applications in which they would most likely appear if deployed during the 1990s. Also shown in the table are the principal conventional alternatives against which these technologies are most likely to compete. Applications are divided between those in which electrical power output is controlled by the utility (dispatchable) and those where it is not (nondispatchable). Dispatchable applications are further broken down into base, intermediate, and peaking duty cycles. Nondispatchable applications are divided between those with and without storage capabilities.

Many of these technologies **offer modular design features that eventually could allow utilities to add generating capability in small increments with short lead-times and less concentration of financial capital. Other attractive features common to some but not all of these technologies include fewer siting and regulatory barriers, reduced environmental impact, and increased fuel flexibility and diversity**. Virtually all of the technologies considered in this assessment offer the potential of sizable deployment in electric power generation applications beyond the turn of the century. **At the current rate of development, however, most developing technologies will not be in a position to contribute more than a few percent of total U.S. electric generating capacity in the 1990s, and therefore, will not be of much help in meeting accelerated demand, should it occur.[3]**

Cost and Performance

The current cost and performance characteristics (including the uncertainty in both cost and performance) of most new technologies are

[2]For purposes of this report we define renewable technologies as those that do not use conventional fossil and nuclear fuels, i.e., solar thermal-eiectric, photovoltaics, wind turbines, and geothermal. All others we refer to as nonrenewable technologies.

[3]Here and elsewhere in this report, a contribution to U.S. electricity supply is considered "significant" when it amounts to 5 to 10 percent or more of total generating capacity, or the equivalent in terms of electricity storage or reduced demand.

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Box A.—Developing Technologies Considered in OTA's Analysis

Generating Technologies:

- *Photovoltaics.*—A photovoltaic cell is a thin wafer of semiconductor material which converts sunlight directly into electricity. The cells are grouped into arrays oriented towards the Sun. A photovoltaic installation may consist of any number of arrays, which produce power from a few kilowatts to many megawatts.
- *Solar Thermal-Electric Powerplants.*—These installations convert radiant energy from the Sun into thermal energy, a portion of which subsequently is transformed into electrical energy. The conversion typically employs a generator driven by a turbine.
- *Wind Turbines.*—A wind turbine uses the kinetic energy in wind to rotate a shaft linked to a generator. Wind turbines may be installed alone, or in groups consisting of hundreds of units—so called "windfarms."
- *Geothermal Power Stations.*—Geothermal energy resources are found when geologic anomalies bring heat from the Earth's core close to the surface. A geothermal powerplant taps this energy to drive a turbine-generator. Geothermal heat is brought to the surface occasionally as steam, and used directly to drive a steam turbine. More often, the heat is delivered to the surface in hot water (geothermal brine) and is transferred to a secondary "working fluid" which is subsequently used to drive the turbine. Versions of the latter, binary and dual-flash systems, are emphasized in this study.
- *Fluidized-Bed Combustors (FBC).*—A fluidized-bed is a mass or "bed" of small particles through which flow large volumes of combustion gases. The gases move through the bed at velocities sufficient to cause the mass of particles to behave like a fluid; hence the term "fluidized-bed." In a typical fluidized-bed combustor, solid fuel is fed into the bed continuously and mixed with the bed's hot particles. As the fuel burns, the heat is used to generate steam in tubes which lace the bed. The steam, in turn, drives a turbine and generator.
- *Integrated Gasification/Combined-Cycle (IGCC) Powerplant.*—This type of system consists of two basic elements. The first converts a fuel such as coal into a combustible gas. The second is a combined-cycle system in which the gas is burned and used to drive a combustion turbine; after exiting the gas turbine, the hot combustion gases are used to generate steam which drives a steam turbine. The turbines drive generators which produce electricity. The gasification plant and the combined-cycle unit are integrated to use the thermal energy available from the fuel very efficiently.
- *Fuel Cells.*—A fuel cell produces electricity directly by way of an electrochemical reaction of a fuel such as natural gas; neither combustion nor moving parts are required in the conversion process. It can also be integrated with a coal gasifier. Fuel cells are grouped into "stacks," any number of which may be used in a power facility.

Energy Storage Technologies:

- *Batteries.*—In a battery storage plant, one or more batteries are "charged" when electrical energy is converted to potential energy stored by chemicals within the batteries. When the battery is "discharged," reactions within the battery convert the potential energy back into electricity.

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- *Compressed-Air Energy Storage (CAES) Facilities.*—In this facility, electric power is used to drive compressors which force air into an underground reservoir. When electricity is needed, the air is released and used to drive a turbine and a generator.

Load Management Technologies:

- Load management refers to manipulation of customer demand by economic and/or technical means. This report examines primarily those load management technologies which require utility ownership or control. These consist of devices for measuring and recording information regarding customer power consumption; communications technologies; and technologies which interpret information and automatically effect decisions necessary for effective load management.

not generally competitive with conventional alternatives.[4] Cost reductions, performance improvements, and resolution of uncertainties will all occur as these technologies mature. The rate at which this maturity occurs depends on: 1) sustained progress in research, development, and demonstration to reduce cost, improve performance, and reduce uncertainty in both cost and performance; and 2) continued active demonstration of the technologies, particularly in utility applications to develop the commercial operating experience necessary before utility decisionmakers will consider a new technology seriously. Utility and nonutility interest in these technologies is also affected by a wide range of other factors relating to environmental benefits, siting requirements, and public acceptance.

Lead-Times

Common to the deployment of all electric generating technologies is the need for planning, design, licensing, permitting, other preconstruction activities, and finally construction itself. These steps with some technologies, for early units at a minimum, may take long periods of time—up to 10 years or more. This means that if those technologies still undergoing development are to be commercially deployed in the 1990s, there may be as little as 5 or 6 years in which to complete development and establish in the minds of investors that their costs, performance, and other attributes fall within acceptable ranges.

Specific Generating Technologies

The relative importance of efforts to improve cost and performance versus the need to shorten lead-times in order to attain commercial status varies

[4]In particular, with conventional generating capacity in smaller unit sizes such as conventional combustion turbines, advanced combined-cycle plants, slow-speed diesels, and participation in conventional cogeneration projects.

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Table 1.—Selected Alternative Generating and Storage Technologies: Typical Sizes and Applications in the 1990s

Typical configurations in the 1990s

Installation size (MW)	Dispatchable applications[a]			Nondispatchable applications[b]	
	Base load (60-70% CF)	Intermediate load (30-40% CF)	Peaking load (5-15%)	Intermittent (w/o storage)	Others (not utility controlled)
Greater than 250 MWe	Coal gasification/ combined-cycle	Coal gasification/ combined-cycle	n.a.		
	Conventional coal				
51-250 MWe	Geothermal	Atmosphere fluidized-bed combustor	Compressed air storage (maxi CAES)	Solar thermal Wind	Atmospheric fluidized-bed combustor Solar thermal (w/storage)
	Atmospheric fluidized-bed combustor	Compressed air storage (maxi CAES)	Solar thermal (w/storage)		
		Solar thermal (w/storage)			
	Combined-cycle plants	Combined-cycle plants	Combustion turbine		
1-50 MWE	Geothermal Atmospheric fluidized-bed combustor Fuel cells	Fuel cells Compressed air storage (maxi CAES) Solar thermal (w/storage)	Compressed air storage (mini CAES) Battery storage Fuel cells Solar thermal (w/storage)	Solar thermal Wind Photovoltaics	Atmospheric fluidized-bed combustor Geothermal Fuel cells Solar thermal (w/storage) Battery storage Compressed air storage (mini CAES) Geothermal
			Combustion turbine		Combustion turbine
Less than 1 MWe				Solar thermal Wind Photovoltaics	Fuel cells Battery storage

NOTES: For each unit size and application, new technologies are shown above the dotted line and conventional technologies are shown below the dotted line. CF = capacity factor and n.a. = not applicable.

[a]Dispatchable technologies may not be utility-owned.

[b]Note that nondispatchable technologies may serve base, intermediate, or peaking loads.

SOURCE: Office of Technology Assessment.

by technology. This distinction, in particular, makes it convenient to divide the technologies considered here into two basic groups:

1. The first consists of technologies envisioned primarily for direct electric utility applications, and includes IGCC; large (>100 MW) AFBC; large (>100 MW) Compressed Air Energy Storage (CAES) facilities; large (>50 MW) geothermal plants; utility-owned fuel cell powerplants; and solar thermal central receivers.
2. The second group consists of technologies that are characterized as suitable either for utility or nonutility applications, and includes small (<100 MW) AFBCs in nonutility cogeneration applications; fuel cells small (<100 MW) CAES; small (<50 MW) geothermal plants; batteries; wind; and direct solar power generating technologies such as photovoltaics and parabolic dish solar thermal.

In both groups, the goal of research, development, and demonstration is to improve cost and performance characteristics to a point where the technologies are commercially competitive. For the first group of technologies, however, the likelihood of long lead-times for early commercial units is the primary constraint to extensive use in the 1990s. Technologies in the second group are likely to have shorter lead-times and are often smaller in generating capacity. For most of them to make a significant contribution in the 1990s, however, their research, development, and demonstration will have to be stepped-up in order to reduce cost to levels acceptable to utility decisionmakers and nonutility investors, and resolve cost and performance uncertainties.

It is important to note that the distinction between these two groups of technologies is not rigid. Technologies in the first group also could benefit from accelerated research and development while those in the second group could be held back by long lead-times.

In addition, many of the technologies in the second group are small enough to qualify as small power producers employed in nonutility power generating projects operating under the provisions of PURPA. **The existence of a wide variety of markets and interested investors outside the electric utilities increases the likelihood that at least some of these technologies will be deployed**.

Because of its modular nature and positive environmental features, the IGCC has the potential for deployment lead-times of no more than 5 to 6 years. Early commercial units, however, may require longer times—up to 10 years—because of regulatory delays, construction problems, and operational difficulties associated with any new, complex technology; and it may take a number of commercial plants before the short lead-time potential of the IGCC is realized. In addition, despite the success of the Cool Water demonstration project, a 100 MWe IGCC plant that has increased electric utility confidence in the technology, more operating experience is likely to be required before there will be major commitment to the IGCC by a cautious electric utility industry. Therefore, **unless strong steps are taken to work closely with regulators and to assure quality construction**

for these initial plants, there may be insufficient time remaining after utilities finally make a large commitment to the IGCC for the technology to make a significant contribution before 2000. As has been shown in the Cool Water project, though, such steps are possible, and they may be facilitated if initial commercial units are in the 200 to 300 MWe range rather than the current design target of 500 MWe.

The first large (about 150 MW), "grass-roots" (i.e., not retrofits of existing facilities) AFBC installations for generating electricity also may be subject to long lead-times. Moreover, a large AFBC demonstration unit probably will not even be operating until 1989. It now appears unlikely that the operation of that unit will be sufficient to justify large numbers of orders within the first few years of the 1990s. The AFBC, however, also has the potential for needing lead-times on the order of only 5 years. Further, favorable experience with smaller AFBC cogeneration units and AFBC retrofit units which will be in service by 1990 may provide the commercial experience needed to accelerate deployment of the larger units.

Foremost among new technologies offering the potential of significant deployment in the 1990s are small (below 100 MWe) AFBC plants in cogeneration applications and larger (100 to 200 MWe) AFBC retrofits to existing coal-fired powerplants. By 1990, plants of both types will be operating. Over a dozen commercial cogeneration plants using AFBC have been started by nonutilities, and two large utility retrofit projects are underway. These first plants appear capable of producing electricity at lower costs than their solid-fuel burning competitors (including the IGCC and large, electric-only, grass-roots AFBCs) in the 1990s. The prospects are good that additional orders—perhaps mostly from nonutilities—will be forthcoming and that large numbers of these AFBC units could be operating by the end of the century.

While the prospects for wind turbines are clouded by the anticipated termination of the Renewable Energy Tax Credits (RTCs) and other potential tax changes, the outlook nevertheless appears promising. By the end of 1984, an estimated 650 MWe were in place in wind farms in the United States, mostly in California (550 MWe). Over the early 1980s, capital costs have dropped rapidly and performance improved swiftly. **Improvements are expected to continue, and the cost of electric power from wind turbines, even unsubsidized ones, in high-wind parts of the country may soon be considerably lower than power from many of their competitors**. The rate of improvement will be heavily influenced by future trends in the avoided costs or "buy-back rates" offered by utilities to nonutility electricity producers. Should these costs be low or uncertain, technological development and application will be slowed. Conversely, high avoided costs, stimulated perhaps by rising oil and gas prices or shrinking reserve margins of generating capacity, might considerably accelerate their contribution.

Although geothermal development has been substantial compared to other technologies, most of this development has occurred at The Geysers in California, an unusual high-quality dry steam resource (one of only seven

known in the world) that can be tapped with mature technology. All other geothermal resources in the United States require less developed technology to generate power. Two developing geothermal technologies, though, are currently being demonstrated on a small scale and show promise for commercial applications in the West. Current evidence indicates that these technologies—dual flash and binary systems—are very close to being commercial, and that cost and performance will be competitive. Small binary units (about 10 MWe) are already being deployed commercially. These developments, coupled with the fact that the technologies can be put in place with lead-times of 5 years or less, suggest that they could produce considerable electric power in the West by the end of the century. As is the case with wind power, **the growth rate of geothermal power will be sensitive to Federal and State tax policy**.

Initial commercial application of fuel cells should appear in the early 1990s, primarily fired with natural gas. The large and potentially varied market (it includes both gas and electric utilities as well as cogenerators), the short lead-times, factory fabrication of components, and a variety of operational and environmental benefits all suggest that when cost and performance of fuel cell powerplants become acceptable, deployment could proceed rapidly. **The principal obstacle to fuel cells making a significant contribution seems to be insufficient initial demand to justify their mass production.** For such demand to appear in the 1990s, extensive commercial demonstration in the late 1980s will probably be necessary.

The development rate of photovoltaics (PV) has been considerable in recent years, but the technical challenge of developing a PV module that is efficient, long-lasting, and inexpensive remains. While technical progress and deployment of photovoltaics in the United States are likely to be slowed by termination of the RTC or by other changes in Federal or State tax law, or by declining avoided costs, industry activity is likely to remain intense. Aided by interim markets of specialized applications and consumer electronics, PVs could develop to the point where competitive grid-connected applications at least begin to appear in the 1990s. In the 1990s, overseas markets may dominate the industry's attention, stimulating and supporting improvements in cost and performance, and encouraging mass production to further reduce costs. However, European and Japanese vendors, assisted by their respective governments, have been more successful than U.S. vendors in developing these markets. Foreign competition is likely to be a major concern for U.S. vendors over the next decade.

Of the solar thermal technologies, solar parabolic dish technologies offer the most promise over the next 10 to 15 years; although with current uncertainty in cost and performance, solar troughs may be competitive as well. Characteristics of some solar dish and trough designs indicate that they could be rapidly put in place in areas such as the Southwest. The cost of power generation using these designs in such regions could be very close to those of conventional alternatives. Some demonstration and subsidized commercial units already are operating. **Full commercial applica-**

tion, however, will require further demonstrations of the technologies over extended periods of time; such demonstrations must be started no later than 1990 if the technologies are to be considered seriously by investors in the 1990s. The likelihood of such demonstrations appears now to depend on the availability of some kind of subsidy. In particular, **development of the technology to date has depended heavily on the RTC**.

Other solar thermal technologies, including central receivers and solar ponds, while showing long-term promise, are unlikely to be competitive with other electric generating alternatives or have sufficient commercial demonstration experience to yield any significant contribution through the 1990s. The central receiver, however, is of continuing interest to some Southwestern utilities in the long term because it offers a favorable combination of advantages including the potential for repowering applications, high efficiency, and storage capabilities.

Along with new generating technologies, this assessment examined two electric energy storage technologies—compressed air energy storage (CAES) and batteries—that show long-term promise in electric utility applications.

Because of potentially long lead-times, CAES appears to have only limited prospects in the 1990s. The large-scale (>100 MW) version of this technology (called maxi-CAES) currently has an estimated lead-time of 5 to 8 years; of this, licensing and permitting and other preconstruction activities is expected to take 2 to 4 years. Moreover, while commercial installations are operating in Europe, no plant yet exists in the United States. Despite strong evidence that this technology offers an economic storage option, CAES is unlikely to be the target of much investment until a demonstration plant is built. No plans for a demonstration plant currently exist. Further, while a demonstration project should prove the technology, the peculiar underground siting problems and unfamiliarity with the CAES concept may still limit early application.

A smaller alternative—mini-CAES (<100 MW)—promises to have a much shorter lead-time due to modularity of the above-ground facilities and short (30-month) construction lead-times. Here too, however, unless a demonstration plant is started in the next few years, extensive deployment before the end of the century is improbable.

Resolution of a variety of cost and performance uncertainties remains before extensive use of advanced battery storage systems can be anticipated. If the technical problems can be resolved in a timely fashion and demonstration programs are successful, however, rapid deployment in electric utility applications could occur, due to the short lead-times and cost reductions associated with mass production. Of the candidates, lead-acid and zinc-halogen batteries appear to show the most promise.

Table 2 summarizes the major electric power generating projects utilizing these technologies installed or under construction as of May 1985.

Table 2.—Developing Technologies: Major Electric Plants Installed or Under Construction by May 1, 1985

Technology	Capacity	Location	Primary sources of funds	Status
Wind turbines[a]	550+ MWe (gross)[b]	California wind farms	Nonutility	Installed
	100+ MWe (gross)[c]	U.S. wind farms outside of California	Nonutility	Installed
	? MWe[d]	All U.S. wind farms	Nonutility	Under construction (1986)
Solar thermal electric:				
Central receiver	10 MWe (net)[e]	Daggett, CA	Utility, nonutility, and Government	Installed
	0.75 MWe	Albuquerque, NM	Utility, nonutility, and Government	Installed
Parabolic trough	14 MWe (net)	Daggett, CA	Nonutility	Installed
	30 MWe (net)	Daggett, CA	Nonutility	Under construction (1986)
Parabolic dish	0.025 MWe (net)[f]	Palm Springs, CA	Government	Installed
	2 × 0.025 MWe (net)[f]	Various locations	Nonutility	Installed
	2 × 0.025 MWe (net)[f]	Various locations	Nonutility	Under construction
	3.6 MWe	Warner Springs, CA	Nonutility	Installed
Solar pond	None			
Photovoltaics:				
Flat plate	1 MWe (dc, gross)	Sacramento	Utility and Government	Installed
	1 MWe (dc, gross)	Sacramento, CA	Utility and Government	Under construction (1985)
	1 MWe (dc, gross)	Hesperia, CA	Nonutility	Installed
	6.5 MWe (dc, gross)	Carrisa Plains, CA	Nonutility	Installed
	0.75 MWe (dc, gross)	Carrisa Plains, CA	Nonutility	Under construction
Concentrator	4.5 MWe (dc, gross)	Borrego Springs, CA	Nonutility	Installed[g]
	1.5 MWe (dc, gross)	Davis, CA	Nonutility	Installed[g]
	3.5 MWe (dc, gross)	Barstow, CA	Nonutility	Installed[g]
Geothermal:				
Dual flash	47 MWe (net)	Heber, CA	Nonutility	Under construction (1985)
Binary:				
Small	2 × 3.5 MWe	Mammoth, CA	Nonutility	Installed
	3 × 0.3 MWe	Hammersly Canyon, OR	Nonutility	Installed
	3 × 0.4 MWe	Hammersly Canyon, OR	Nonutility	Installed[h]
	10 MWe	East Mesa, CA	Nonutility	Installed
	1 × 0.75 MWe (gross)	Wabuska, NV	Nonutility	Installed
	3 × 0.35 MWe (gross)	Lakeview, OR	Nonutility	Installed[h]
	3 × 0.45 MWe (gross)	Lakeview, OR	Nonutility	Installed[h]

[a]Includes small- and medium-sized wind turbines.
[b]Approximately 550 MWe were operating in California at the end of 1984. It is not known how much additional capacity was installed by May 1985.
[c]Approximately 100 MWe were operating outside of California at the end of 1984. It is not known how much additional capacity had been installed outside California by May 1985.
[d]It is not known how much capacity was under construction on May 1, 1985.
[e]This facility, the Solar One Pilot plant, is not a commercial-scale plant and differs in other important ways from the type of system which might be deployed commercially in the 1990s.
[f]This installation consists of only one electricity producing module; a commercial installation probably would consist of hundreds of modules.
[g]Only 10 percent of the modules were operating at the time because of problems with the power conversion systems.
[h]Installed but not operating, pending contractural negotiations with utilities.

Table 2.—Developing Technologies: Major Electric Plants Installed or Under Construction by May 1, 1985—Continued

Technology	Capacity	Location	Primary sources of funds	Status
	4 × 1.25 MWe (gross)	Sulfurville, UT	Nonutility	Under construction (1985)[i]
	3 × 0.85 MWe (gross)	Sulfurville, UT	Nonutility	Under construction (1985)[i]
Large	45 MWe (net)	Heber, CA	Utility, nonutility, and Government	Installed
Fuel cells:				
Large	None			
Small[j]	38 × 0.04 MWe (net)	Various locations	Utility, nonutility, and Government	Installed
Small[j]	5 × 0.04 MWe (net)	Various locations	Utility, nonutility, and Government	Under construction
Fluidized-bed combustors:				
Large grass roots	160 MWe	Paducah, KY	Utility[k] and Government	Under construction (1989)
Large retrofit	100 MWe	Nucla, CO	Utility[k]	Under construction (1987)
	125 MWe	Burnsville, MN	Utility[k]	Under construction (1986)
	125 MWe	Brookesville, FL	Nonutility	Under construction (1986)
Small cogeneration	30 MWe	Colton, CA	Nonutility	Under construction (1985)
	25 MWe	Fort Wayne, IN	Nonutility	Under construction (1986)
	15 MWe	Ione, CA	Nonutility	Under construction (1987)
	67 MWe	Chester, PA	Nonutility	Under construction (1986)
	90 MWe[l]	Decatur, IL	Nonutility	Under construction (1986)
	50 MWe[m]	Cedar Rapids, IA	Nonutility	Under construction (1987)
	3.5 MWe	Pekin, IL	Nonutility and Government	Installed
	28 MWe	Pontiac, MI	Nonutility	Under construction (1986)
	2.8 MWe	Washington, DC	Nonutility and Government	Installed
	24 MWe	Enfield, ME	Nonutility	Under construction (1986)
	20 MWe	Chinese Station, CA	Nonutility	Under construction (1986)
IGCC[n]	100 MWe	Daggett, CA	Utility, nonutility, and Government	Installed
Batteries:				
Lead acid[o]	0.5 MWe	Newark, NJ	Utility and Government	Installed
Zinc chloride	None[p]			
CAES:				
Mini	None			
Maxi	None			

[i]The equipment modules have been delivered to the site; site preparation, however, has not started.
[j]These units are not commercial-scale units.
[k]Including the Electric Power Research Institute.
[l]This is the total capacity which may be generated from the four AFBC boilers which will be installed.
[m]This is the total capacity which may be generated from the two AFBC boilers which will be installed.
[n]While this installation, the Cool Water unit, uses commercial-scale components, the installation itself is not a commercial-scale installation.
[o]While this installation at the Battery Energy Storage Test Facility uses a commercial-scale battery module, the installation itself is not a commercial-scale installation.
[p]A 0.5-MWe zinc chloride commercial-scale battery module was, however, operating at the Battery Energy Storage Test facility until early 1935.

SOURCE: Office of Technology Assessment.

CONVENTIONAL ALTERNATIVES IN THE 1990s

The contribution of developing technologies over the next two decades depends in part on the relative cost and performance of conventional generating options as well as a variety of options for extending the lives or otherwise improving the performance of existing generating facilities.

New Capacity

To the extent that new generating capacity is needed at all over the next two decades, conventional pulverized coal plants, combustion turbines, and advanced combined-cycle plants will continue to be the principal benchmark against which utilities and others will compare developing generating technologies. Utilities are very interested, however, in smaller unit sizes of even these technologies. Also, if nuclear power is to become a realizable choice again for utilities, it is likely to involve smaller, standardized units.

If hydroelectric opportunities are available, they are likely to be exploited in both run-of-river and pumped storage applications; few new hydroelectric opportunities, though, are likely through the 1990s. Similarly, refuse steam plants, biomass technologies (e.g., wood waste-fired power generation), slow-speed diesels, and vapor-dominated geothermal plants all use mature technologies so that where opportunities exist, they are likely to be chosen over newer technologies.

In addition, enhancements to conventional plants such as limestone injection in coal boilers, coal-water fuel mixtures, and others will all be reviewed carefully along with new generating technologies as utilities plan for new capacity. The availability of such enhancements could significantly affect the relative attractiveness of new technologies in the 1990s.

Plant Betterment

By 1995, the U.S. fossil steam capacity will have aged to the point where over a quarter of the coal and nearly half of the oil and gas steam units nationwide will be over 30 years old. In the past, the benefits of new technology often outweighed the benefits of extending the useful lives of existing generating facilities, rehabilitating such facilities to improve performance or upgrade capacity, or even repowering such plants with alternative fuels. All of these so-called plant betterment options are receiving renewed interest by utilities because plants "reaching their 30th birthday" over the next decade have attractive unit sizes (100 MW or larger) and performance (heat rates close to 10,000 Btu/kWh). For that reason, **rehabilitating or simply extending the lives of such units, frequently at much lower anticipated capital costs than that of new capacity, are often very attractive options for many utilities.** Prospects are particularly bright if units are located at sites close to load centers and the rehabilitation does not trigger application of New Source Performance Standards, i.e., more stringent air pollution controls.

In many instances, plant betterment can also improve efficiency up to 5 to 10 percent and/or upgrade capacity. Additional benefits from such projects include possible improvements in fuel flexibility or reduced emissions of existing generating units at modest cost relative to that of new capacity. Finally, an initial market for some new technologies such as the AFBC are in repowering applications, e.g., where an existing pulverized coal plant is retrofitted with an AFBC boiler.

Load Management

Load management refers to manipulation of customer demand by economic and/or technical means. It is done for the mutual benefit of both utility and customer, usually as a means to provide maximum productivity of the utility's generation and distribution capacity. While load management is not a substitute for all new capacity needs, it can enable a given capacity to satisfy a greater customer base, and operate at maximum efficiency. It is now employed by some utilities and being seriously considered by many others to improve their load factor—the ratio of average to peak load. Since base load generating equipment is generally more thermally efficient than peak load equipment, one of the principal goals of load management is to encourage a shift of demand to off-peak periods. The other is to defer the need for costly new generating capacity by inhibiting demand during peak periods. This assessment focuses on technology-based direct load control technologies employing advanced meters and utility-owned or controlled load control systems. A potentially important feature of load management is that it can help reduce future demand growth uncertainty if the saturation and use of load management devices can be more accurately predicted. If such predictions are not possible, however, then increased load management may actually increase demand uncertainty.

Based on the results of current load management programs and ongoing experiments, load management technologies are expected to be able to be deployed at costs below those associated with many conventional generating alternatives. In many instances, however, these costs cannot be reached without substantial utility demand to encourage manufacturers to realize volume production economies.

Widespread deployment of load management in the 1990s will depend on continued experimentation by utilities to resolve operational uncertainties; the refinement of load management equipment and techniques, including adequate demonstration of communications and load control systems; development of incentive rate structures; and a better understanding of customer acceptance. Commitments to initiate load management systems will also depend on the nature of a utility's demand patterns and capacity mix, the attitudes of utility decisionmakers, and on public utility commission actions. The degree of public utility commission support, in particular, is likely to be very important over the next decade.

IMPACT OF DISPERSED GENERATING TECHNOLOGIES ON SYSTEM OPERATION

As the participation in U.S. electric power systems of nonutility owned and operated dispersed generating sources (DSGs) increases, the implications for system operation, performance, and reliability are receiving increased attention by the industry. **For the most part, however, the technical aspects of interconnection and integration with the grid are fairly well understood and most utilities feel that the technical problems can be resolved with little difficulty**. State-of-the-art power conditioners are expected to alleviate utility concerns about the quality of interconnection subsystems. A number of nontechnical problems remain, though, which could inhibit the growth of DSGs.

Nonutility Interconnection Standards

More utilities are developing guidelines for interconnection of DSGs with the grid. A number of national "model" guidelines are being developed by standard-setting committees for the Institute of Electrical and Electronic Engineers, the National Electric Code, the U.S. Department of Energy, and the Electric Power Research Institute, although none has yet released final versions and widespread utility endorsement is still uncertain. As a result, **DSG owners are likely to face different and sometimes conflicting interconnection equipment standards well into the 1990s. These differences may hamper both the use of DSGs as well as the standardized manufacture of interconnection equipment**.

Interconnection Costs

The costs of interconnection have declined dramatically in recent years, particularly for smaller DSGs. Typical costs range from $600/kW for 5 kW units to less than $100/kW for 500 kW or larger units. The interconnection costs for multi-megawatt DSGs are only a small fraction of the total cost of the facility. While future technological advances in microprocessor controls and less costly nonmetallic construction could bring costs down even further, the major cost decrease is expected to come from volume production of equipment. As mentioned above, though, this volume production may be delayed until national model interconnection guidelines are agreed on for interconnection equipment.

REGIONAL DIFFERENCES

A particularly important factor affecting the relative advantages of new electric generating, storage, and load management technologies is the region in which a utility or prospective nonutility power producer is located.

U.S. regions differ markedly in industrial base, demographic trends, and other factors affecting electricity demand; the age and composition (particularly fuel use) of existing generating facilities; the nature and magnitude of available indigenous energy resources; regulatory environment; transmission infrastructure and prospects for bulk power transfers; and other factors affecting the selection of electric power technologies.

Existing Generation Mix

The regional mix of existing generating facilities is likely to profoundly affect the relative attractiveness of new generating capacity. While most electric utility systems with substantial oil and gas capacity are expected to decrease use of these fuels over the next decade, **reliance on these fuels is expected to be strong enough in some areas, i.e., New England, the Gulf and Mid-Atlantic States, the Southeast, and the West, that the economics of competing technologies will remain particularly sensitive to the price and availability of oil and gas**. This will apply even more strongly in the few States such as Florida where, due to expectations of high demand growth and continued decreases in (or stabilization of) oil prices, utility systems are actually forecasting increased use of oil.

In California oil- and gas-fired generation, while declining, is projected to remain above 33 percent of the total electricity generation in the State through the end of the century (oil alone will be 15 percent). Similarly, if present trends continue in Texas, oil and gas is projected to account for 35 percent of total generation and about 50 percent of total capacity over the same time period. In both States, high avoided cost rates resulting from continued reliance on oil and gas enhances the attractiveness of cogeneration, in particular, while the favorable tax climate in California enhances the attractiveness of renewable power generation projects initiated under PURPA. **In some States where oil and gas are the dominant fuels, especially California, Louisiana, and Texas, cogeneration may constitute a significant fraction of total installed capacity by the end of the century**. Some utilities in Texas, for example, are already planning for cogeneration contributions of as much as 30 percent.

The age of existing power generating facilities varies widely among U.S. regions. As a result, the prospects for life extension and plant rehabilitation vary as well. For example, Texas, the Southeast, and the States west of the Rockies will have the highest percentage increases in plants that would be logical candidates for such options between now and 1995, i.e., those generating units that will have been in operation more than 30 years. In terms of total installed capacity, the opportunities for life extension will be greatest in the Mid-Atlantic, Southeast, Gulf, and Western States. Site-specific economics will determine actual implementation levels.

Interregional Bulk Power Transactions

It appears that existing interutility and interregional transmission capabilities are being nearly fully utilized in the United States. Hence, the

prospects for large increases in bulk power purchases among utilities using existing transmission capabilities will be limited. **Some regions**, however, such as portions of the West and Midwest, **are continuing to expand generation and transmission facilities in anticipation of serving the bulk power markets**. In addition, major transmission projects are underway in New York, New England, the upper Midwest, and the Pacific Northwest to allow these regions to purchase lower cost hydroelectric power generated in Canada from existing and proposed facilities.

Load Management

OTA has found that the prospects for increased load management in future utility resource planning vary by region. Perhaps more importantly, they also vary significantly by utility within reliability council regions. Moreover, utilities' objectives for pursuing load management vary as well. For example, utilities with very high current or anticipated reserve margins (many in the Midwest), are interested in load management to better use existing base load capacity, i.e., to stimulate increased demand in off-peak periods. Other utilities with very low current or anticipated reserve margins are pursuing load management primarily to reduce peak demand and defer the need for new capacity additions. Municipal utilities and rural cooperatives, which accounted for most of the points controlled by load management in 1983, are expected to continue to provide a strong load management market in all regions through the 1990s.

Reliability Criteria

An important indicator of a region's need for new generating capacity is reflected in measures of projected power system reliability. Such measures include the reserve margin—i.e., amount of installed capacity available in excess of the peak load, traditionally expressed as a percentage of the total installed capacity. Reserve margins, as well as other reliability measures, are sensitive to demand predictions, scheduled capacity additions and retirements, and other factors such as scheduled maintenance and adjustments for forced outages or firm power purchases and sales from other utilities.

The anticipated reserve margins over the next several decades vary considerably by region. Under medium demand growth (2.5 percent average annual growth through 1995), reserve margins are expected to dip as low as 15 percent (in the upper Midwest in the early 1990s) and peak as high as 47 percent (in the West in the mid-1980s). Under higher demand growth, power pools in all regions may fall below acceptable reliability levels in the early 1990s. Under low demand growth (less than 2 percent), reliability levels are likely to be adequate in all regions through the early 1990s.

Renewable Resources

Increased use of solar, wind, and geothermal resources in U.S. electric power generation will vary regionally due to both the relative cost of alter-

native generation and the availability of high-quality renewable resources. For example, while wind regimes are promising for wind turbines in many areas across the country, they are currently being developed mostly in California where high utility avoided cost and a favorable tax climate has encouraged their development in nonutility power production applications under PURPA. In addition, a State-sponsored wind resource assessment program has spurred development. A similar situation exists for photovoltaics and geothermal power, although geothermal development is much more regionally limited to the West. Solar thermal power generation, for the next several decades at least, may be viable only in the Southwest and perhaps the Southeast where solar insolation characteristics may be sufficient to make projects competitive and where land availability is not a major constraint on development.

UTILITY AND NONUTILITY INVESTMENT DECISIONS

Prior to the 1970s, maintaining power system reliability was treated as a prescribed constraint and utilities had little difficulty earning their regulated rate of return on investment while achieving steady reductions in the cost of electricity by building larger, less capital-intensive powerplants. Hence, utility decisionmaking objectives of maintaining service reliability, maximizing corporate financial health, and minimizing rates could generally be pursued simultaneously.

Because of the complex and uncertain investment decision environment that has evolved since the 1970s, utilities have begun to consider offering varying levels of service reliability and to more sharply weigh trade-offs between stockholders' and ratepayers' interests in making new plant investment decisions. **In many instances, utilities are avoiding making large-scale plant commitments and, indeed, are considering the host of options cited earlier that can defer the need for such commitments.**

Utility Investment

Of particular interest to many utilities are the potential benefits of increased planning flexibility and financial performance offered by small-scale, short lead-time generating plants. For example, **OTA modeling studies indicate that with uncertain demand growth, the cash flow benefits of such plants can be considerable.** This is true, in some cases, even when the capital cost per kilowatt of the smaller plants is as much as 10 percent more than for large plants. In addition, the corresponding revenue requirement under a small plant scenario can be lower over a 30-year period.

Electric utility efforts to exploit these financial benefits and nonutility interest in exploiting potentially attractive investment opportunities under PURPA have already stimulated considerable interest from both types of investors in smaller scale generating technologies. **Other benefits are important as well, including less environmental impact, less "rate shock" to consumers by adding generating units to the rate base in smaller in-**

crements, increased fuel diversity, and reduced transmission requirements if generating units can be sited closer to load centers.

Most of the generating technologies considered in this assessment offer the small-scale modular features attractive to many utilities as a means of coping with financial and demand uncertainties. This is likely to make the long-term prospects of these technologies very bright. **Despite this long-term promise, however, in most regions for the next 10 to 15 years most of the new generating technologies are not likely to be competitive with other often more cost-effective strategic options cited earlier**—life extension and rehabilitation of existing generating facilities, increased purchases of power from other systems, and intensified conservation and load management efforts.

Nonutility Investment

Nonutility interest is likely to continue to be limited for the most part to more mature technologies that can be implemented in cogeneration applications or can qualify for favorable tax treatment, e.g., combustion turbines, wind, and more recently AFBC. Investors in nonutility power projects seek to maximize the risk-adjusted return on their invested capital. Depending on the type of investor, other considerations are important as well including tax status, timing of the investment, cash flow patterns, and maintenance of a balanced portfolio of investments with varying risk. In order to finance a new nonutility project, the major risks (technology, resource, energy price, and political) must either by mitigated or incorporated in contingency plans. Common risk reduction techniques used to date include vendor guarantees (or having the equipment vendor take an equity position in the prospective venture) or take-or-pay contracts with utilities.

CURRENT AND FUTURE STATE OF ALTERNATIVE TECHNOLOGY INDUSTRY

Many of the new generating technologies considered in this assessment are being developed by a much wider range of firms than has traditionally dealt with the electric utility industry. Moreover, many firms involved in deploying some new technologies, to the extent that they are being deployed, are small independent firms, less than 3 years old. For example, the wind industry's equipment sales have for the most part been to third-party financed wind parks selling power to utilities under PURPA; many of these parks have been developed by the wind manufacturers themselves. Other developers are large aerospace, petroleum, or other companies that have also not traditionally dealt with electric utilities, and many of them are only beginning to develop working business relationships with them.

Most of the technologies considered in this assessment are in a transition phase of their development, i.e., between pilot- and commercial-scale demonstrations or early commercial units. Some of these technologies are

progressing through this transition aided by the existence of auxiliary markets (in many cases foreign) other than the grid-connected power generation market. For example, small-scale AFBC technology has matured in the industrial marketplace, primarily in process heat applications. Similarly, while the PV technology that will ultimately begin to penetrate grid-connected power generation markets is not yet clear, the various candidates (flat plate, amorphous silicon, concentrators, etc.) are maturing in other markets such as consumer electronics or remote power applications.

As most of these technologies mature and the relationships of vendors and manufacturers with utilities and nonutility power producers develop, the nature of negotiated agreements between the parties initiating commercial demonstrations or early commercial units may dictate the pace of commercial deployment of the technologies. In particular, **the allocation of risks in the form of performance or price guarantees or other mechanisms will be especially important for the electric utility market**. For example, an equipment manufacturer's agreement to hold an equity position in early commercial projects might be viewed by many utilities as an adequate performance guarantee.

One of the problems facing increased deployment of some new generating technologies in the 1990s, as mentioned earlier, was that of potential delays in lead-times of early commercial projects. While the features of smaller scale and modular design for many of these technologies offer ultimate promise for very short lead-times, **experience to date indicates that the rate of deployment of some new generating technologies is being lowered because lead-times being experienced by early commercial projects have been longer than anticipated, partially due to the time needed to complete regulatory reviews**. As regulatory agencies become more familiar with the technologies, the time to complete such reviews should decrease, although this is by no means guaranteed as evidenced by the history of other generating technologies.

The pressures of competition from foreign vendors, many of whom are heavily supported by their governments, as well as the current lack of U.S. demand for some of these new technologies in grid-connected power generation applications, and the pending changes in favorable tax treatment throw into doubt the continued commitment of U.S. firms who are currently developing these technologies. For some technologies, such as wind turbines, solar thermal-electric technologies, and photovoltaics (at least those focusing on concentrator technologies), the survival of some domestic firms may be at stake. Many domestic firms may not be able to compete in world markets over the next decade. However, in some cases foreign markets are considered to be interim markets for technologies as they mature to the point where they can compete in the U.S. grid-connected power generation market.

FEDERAL POLICY OPTIONS

Accelerated demand growth, coupled with current problems in building conventional, central station powerplants, could lead to serious difficulty in meeting new demand in the 1990s. **As a result it may be prudent to ensure the availability of an array of new generating technologies.** Then, the buyers in the market for generating technologies will have a broader range of technologies from which to choose. To ensure this **availability** will probably require a sustained Federal involvement in the commercialization of new electric power generating, storage, and load management technologies. The most logical goals for the Federal initiatives are:

- reduce capital cost and performance uncertainty,
- encourage utility involvement in developing technologies,
- encourage nonutility role in commercializing developing technologies, and
- resolve concerns regarding impact of decentralized generating sources (and load management) on power system operation.

The first three are primary goals while the fourth is less critical although still important. The relative importance of these goals as well as the efforts to achieve them are at the center of the debate over future U.S. electricity policy. A range of possible initiatives is summarized in table 3 along with the Federal actions that would most likely be required to implement them.

Table 3.—Policy Goals and Options

Reduce capital cost, improve performance, and resolve uncertainty:
1. Increase Federal support of technology demonstration
2. Shorten project lead-times and direct R&D to near-term commercial potential
3. Increase assistance to vendors marketing developing technologies in foreign countries
4. Increase resource assessment efforts for renewable energy and CAES resources (wind, solar, geothermal, and CAES-geology)
5. Improve collection, distribution, and analysis of information
Encourage nonutility role in commercializing developing technologies:
1. Continue favorable tax policy
2. Improve nonutility access to transmission capacity
3. Develop clearly defined and/or preferential avoided energy cost calculations under PURPA
4. Standardize interconnection requirements
Encourage increased utility involvement in developing technologies:
1. Increase utility and public utility commission support of research, development, and demonstration activities
2. Promote involvement of utility subsidiaries in new technology development
3. Resolve siting and permitting questions for developing technologies
4. Other legislative initiatives: PIFUA, PURPA, and deregulation
Resolve concerns regarding impact of decentralized generating sources on power system operation:
1. Increase research on impacts at varying levels of penetration
2. Improve procedures for incorporating nonutility generation and load management in economic dispatch strategies and system planning

SOURCE: Office of Technology Assessment.

Research, Development, and Demonstration

Perhaps foremost among the options necessary to accelerate technology development is a sustained Federal presence in research, development, and demonstration of new electric generating, storage, and load management technologies. While **most of these technologies are no longer in the basic research phase, development hurdles are still formidable and the importance of research, development, and demonstration remains high; if these hurdles are overcome the result could be a quick change in competitive position for many of these technologies**. For example, proof of satisfactory reliability during a commercial utility-scale demonstration of AFBC could substantially accelerate its deployment among electric utilities. As noted, the technology already is beginning to be deployed very quickly in smaller scale commercial cogeneration applications.

A critical milestone in utility or nonutility power producer acceptance of new technology is completion of a successful commercial demonstration program. The utility decisionmaking caution cited earlier confers added importance to advanced commercial demonstration projects. While there is considerable debate in the industry over what constitutes an adequate demonstration, two basic categories are often distinguished: One is a proof-of-concept phase which provides the basic operational data for commercial designs as well as test facilities designed to prove the viability of the technology under nonlaboratory conditions and to reduce cost and performance uncertainties. The other involves multiple applications of a more or less mature technology designed to stimulate commercial adoption of the technology. Generally, activities in the first category are necessary for demonstrating commercial viability and activities in the second category are necessary for accelerating commercialization.

The length of the appropriate demonstration period will vary considerably by technology. However, adequate demonstration periods (perhaps many years for larger scale technologies) are crucial to promoting investor confidence. **Moreover, the nature of the demonstration program—i.e., who is participating, who is responsible for managing it, and the applicability of the program to a wide variety of utility circumstances—is of equal importance. Among the most successful demonstration ventures have been and are likely to continue to be cooperative ventures between industry (manufacturers and either utilities or nonutility power producers) and the Federal Government, with significant capital investments from all participants in the venture**. The current AFBC, IGCC, and geothermal demonstrations are good examples. In particular, **for larger scale technologies in utility applications, cooperative industry-government demonstration efforts, managed by the utilities, have a good track record**. For accelerated deployment, similar projects would be required for fuel cells, CAES, advanced battery technologies, and central receiver solar thermal powerplants.

The relationship between utilities and public utility commissions in early commercial applications of new generating and load management tech-

nologies is an important factor that will affect the deployment of these technologies in the 1990s. In particular, increased research, development, and demonstration activity will require utilities and utility commissions to agree on appropriate mechanisms for supporting such activities. Direct support alone from the rate base for research activities (e.g., as the allowance for contributions to the Electric Power Research Institute) may be desirable and important, but they are not sufficient to assure extensive deployment of these technologies by the 1990s. **Much larger commitments that involve large capital investments such as major demonstration facilities may only be justified by a sharing of the risk between ratepayers, stockholders and, if other utilities would benefit substantially, taxpayers**. One mechanism for supporting such projects is to finance a portion of a proposed project with an equity contribution from the utility and the rest through a "ratepayer loan" granted by the public utility commission. The public utility commission might argue that a candidate demonstration project is too risky for the ratepayer to be subsidizing it, particularly if other utilities could benefit substantially from the outcome if successful and are not contributing to the demonstration, i.e., sharing in the risk. In such cases, there could be a Federal role; for example, the ratepayer contribution to the demonstration could be underwritten by a Federal loan guarantee.

Other Policy Actions

In addition to maintaining a continued presence in research, development, and demonstration and implementing environmental policy affecting power generation, **several other Federal policy decisions affecting electric utilities could influence the rate of commercial development of new generating technologies over the next several years. These include removal of the Powerplant and Industrial Fuel Use Act (PIFUA) restrictions on the use of natural gas, and making PURPA Section 210 benefits available to electric utilities**. These steps could increase the rate of deployment of developing generating technologies, but their other effects will have to be carefully reviewed before and during implementation.

A more liberal power generation exemptions policy under PIFUA or an outright repeal of the Act could, in addition to providing more short-term fuel flexibility for many utilities, be an important step toward accelerated deployment of "clean coal" technologies such as the IGCC which can use natural gas as an interim fuel. Some new technologies such as CAES and several solar thermal technologies use natural gas as an auxiliary fuel and would require exemption from PIFUA.

Permitting utilities to participate more fully in the PURPA Section 210 benefits of receiving avoided cost in small power production is likely to result in increased deployment of small modular power generating technologies, particularly cogeneration. For example, utilities are currently limited to less than 50 percent participation in PURPA qualifying cogeneration facilities. In addition, with full utility participation in PURPA, ratepayers likely would share more directly in any cost savings resulting from

these kinds of generating technologies. Allowance of full PURPA benefits for utilities, however, could cause avoided costs to be set by the cost of power from the cogeneration unit or alternative generation technology. Such avoided costs would likely be lower than if they were determined by conventional generating technologies as now is the case. Lower avoided costs would reduce the number of cogeneration and alternative technology power projects started by nonutility investors. Expanded utility involvement, though, may more than compensate for this decrease.

In relaxing the PURPA limitation potential problems require attention, including ensuring that utilities do not show preference for utility-initiated projects in such areas as access to transmission or capacity payments. Moreover, project accounting for PURPA-qualifying projects would probably need to be segregated from utility operations and non-PURPA qualifying projects in order to prevent cross-subsidization which would make utility-initiated projects appear more profitable at the ratepayers' expense. These concerns can be allayed through carefully drafted legislation or regulations, or through careful State review of utility ownership schemes.

As perhaps a logical next step to PURPA, a number of proposals for deregulation of the electric power business have been proposed in recent years, ranging from deregulation of bulk power transfers among utilities, to deregulation of generation, to complete deregulation of the industry. While OTA has not examined the implications of alternative deregulation proposals, such proposals, if enacted, would almost certainly have an impact on new generation technologies. The experiences of PURPA and the Southwest Bulk Power Transaction Deregulation Experiment will be important barometers for assessing the future prospects and desirability of deregulating U.S. electric power generation. **It is important to note that allowance of full PURPA benefits for utilities would be a significant step toward deregulation of electric power generation, at least for smaller generating units.**

Finally, to increase the number of nonutility power projects employing new electric generating technologies, steps to facilitate access to distant markets with streamlined mechanisms for wheeling of power through utility service territories might be an effective way to encourage development of such projects.

Renewable Energy Tax Credits

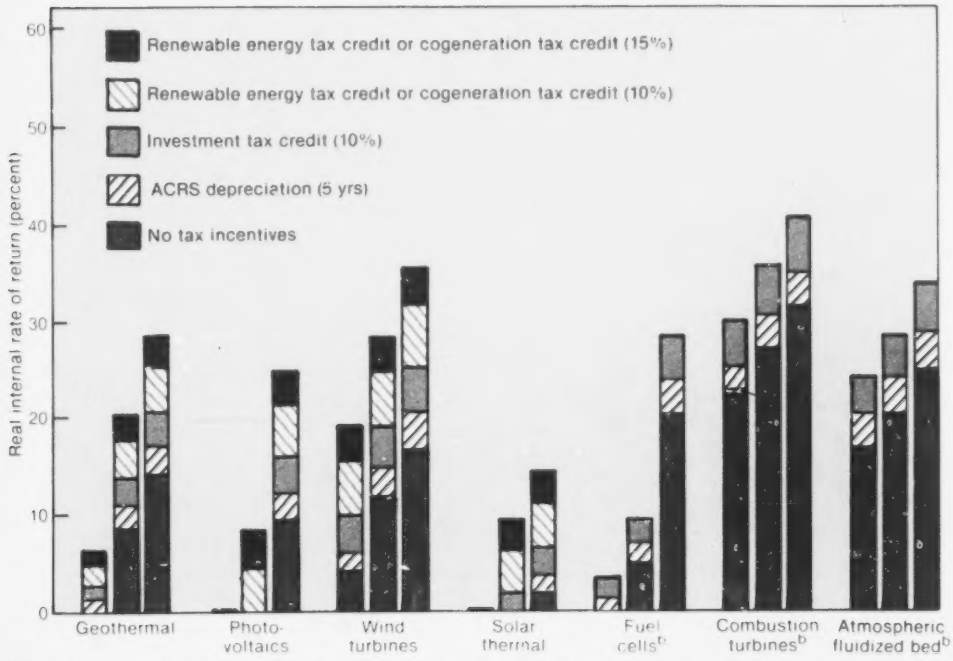
Along with direct support for research and development and joint venture demonstration projects, an important component of the Federal program for new generating technology commercialization has been favorable tax treatment through such mechanisms as the Renewable Energy Tax Credits, the Investment Tax Credit, and ACRS depreciation allowances. **The RTC, in particular, coupled with recovery of full utility avoided costs (under PURPA) by nonutility power producers have been crucial in the initial commercial development and deployment of wind and solar power generating technologies. With declining direct Federal support for renew-**

able technology development, the RTC has supported development of advanced and innovative designs as well as commercial deployment of mature designs. Without some form of favorable tax treatment, deployment of solar, wind, and geothermal technologies is likely to be slowed significantly—certainly in nonutility applications. Without existing tax incentives, many of the mostly small firms involved in development projects will lose access to existing sources of capital. Even large, adequately capitalized firms may lose their distribution networks, making industry growth more difficult.

With favorable tax treatment, some new technologies, such as geothermal and wind, have become important sources of new and replacement generating capacity in the West and Southwest. However, they must compete with more mature, modular technologies, e.g., conventional cogeneration technologies. And these modular technologies will continue to account for an important share of the new generating capacity, in the form of both utility and nonutility owned (and perhaps joint) ventures.

Figure 3 shows the cumulative effect of tax benefits, including accelerated depreciation allowances, Investment Tax Credits, and Renewable Energy Tax Credits on the real internal rate of return for technologies con-

Figure 3.—Tax Incentives for New Electric Generating Technologies: Cumulative Effect on Real Internal Rate of Return[a]



[a]Reported for each technology with "worst case," "most likely," and "best case" estimates of cost and performance for the reference years defined in ch. 4; basic economics assumptions are given in ch. 8.
[b]In cogeneration applications.

SOURCE: Office of Technology Assessment.

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sidered in this assessment under the condition of nonutility ownership. (IGCC is not included in this figure since it is unlikely to be developed in nonutility power projects.) **The figure shows that the RTC may be crucial to the commercial survival of the renewable technologies with the possible exception of wind which may be mature enough to survive without these credits. The number of firms involved in wind technology development, however, would probably decrease markedly without these credits.**

The role of the RTC in accelerating commercial development seems to have changed. The original Federal policy was to provide direct research support to develop the technology and the RTC to accelerate commercial deployment. **With decreased Federal research and development support, the RTC appears to be supporting research and development in the field; this might partially explain the wide variation in performance of wind projects in recent years.**

A frequently proposed alternative to the RTC, in order to ensure performance of projects claiming a credit, is a Production Tax Credit (PTC) which provides benefits only with electricity production. OTA analysis of the PTC shows that geothermal and wind technologies benefit most from a PTC. **Others such as CAES and the direct solar technologies are aided only by a very large PTC. Similarly, tax benefits tied to production discourages producers from testing innovative designs since, if the design does not perform as expected, no benefits will be realized.** Another potential problem with the PTC is that monitoring electricity production may be difficult, particularly in applications that are not grid connected.

Other actions cited earlier for stimulating development in new technology within electric utilities may be more effective than tax preferences. For example, the decrease in the levelized per kilowatt-hour busbar cost for the renewable technologies considered in this assessment, with a 15 percent tax credit over and above the existing tax benefits currently afforded to utilities, is less than 10 percent for all cases.

NOTE: Copies of the full report "New Electric Power Technologies: Problems and Prospects for the 1990s" can be purchased from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, GPO stock No. 052-003-01005-4.

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